VENTURE OIL AND GAS, INC

**Mason 36-14 No. 1 Oil and Gas Production Well**

Off Dorriety Circle

Atmore, Escambia County, AL

Facility No.: 502-0091

# ENGINEERING ANALYSIS

## PROJECT DESCRIPTION

On November 23, 2009, the Department received an air permit application for the Venture Oil & Gas, Inc. Mason 36-14 No. 1 Oil and Gas Production Well located in Section 36, Township 2 North, Range 6 East off Dorriety Circle in Atmore, Escambia County, AL. On November 24, 2009, a complete application was received. The facility will process about 500,000 scf/day of natural gas all of which will be flared until the facility can route the gas to a gas plant for processing. The natural gas contains approximately 1,000 ppm (0.10 mol %) of hydrogen sulfide ($H_2S$).

## PROCESS DESCRIPTION

The well stream will consist of crude oil, water, and sour natural gas. The well stream will flow through the line heater and then to the separator where the crude oil stream, produced salt water stream, and sour natural gas stream will be separated. The crude oil stream will pass through the heater treater and will then be sent to the storage tanks. The produced salt water will be sent to its respective storage tank. The sour natural gas will be sent through a scrubber to drop out any remaining liquids prior to being burned in the flare. The storage tanks are equipped with a vapor recovery unit which will capture and route vapors to the flare for combustion.

The facility will consist of the following emission sources:

- 0.5 MMBtu/hr heater treater
- 0.5 MMBtu/hr line heater
- Process Flare
- Storage Tanks
    - Four 16,800 Gallon Crude Oil Storage Tanks
    - One 16,800 Gallon Saltwater Storage Tank
    - One 21,000 Gallon Crude Oil Storage Tank

## EMISSIONS

The expected potential emissions from the flare are given in Table 1 below.

| Table 1: Total Emissions for Mason 36-14 No. 1 Oil and Gas Production Well | | | | | |
|---|---|---|---|---|---|
| | (Tons/yr) | | | | |
| | PM | $SO_2$ | $NO_X$ | CO | VOC |
| Line Heater | 1.46E-02 | 3.24E-01 | 1.92E-01 | 1.61E-01 | 1.06E-02 |
| Heater Treater | 1.46E-02 | 3.24E-01 | 1.92E-01 | 1.61E-01 | 1.06E-02 |
| Process Flare | | 1.54E+01 | 7.08E+00 | 3.85E+01 | 3.84E+01 |
| Total Facility-wide Emissions | **2.92E-02** | **1.61E+01** | **7.46E+00** | **3.88E+01** | **3.84E+01** |

## REGULATIONS

There are several possible regulations that could apply to the facility equipment:

### State Regulations

1. **ADEM Administrative Code, Rule** 335-3-4-.01(1) states that no person shall emit to the atmosphere an opacity of greater than twenty percent (20%) over a six (6) minute period. The flare and the heaters would be would be subject to this regulation.

2. **ADEM Administrative Code, Rule** 335-3-5-.01(1)(a), "*Fuel Combustion*", limits sulfur dioxide ($SO_2$) emissions from fuel burning equipment in Category II counties to 4.0 pounds per million BTU heat input. The 0.5 MMBtu/hr line heater and 0.5 MMBtu/hr heater treater would each be subject to this regulation since the facility is located in Escambia County which is a Category II County. The $SO_2$ emissions from each of the heaters would be limited to 8.76 tons per year (TPY). Based on Table 1, the $SO_2$ emissions from these heaters would not be expected to exceed the allowable limits. No monitoring would be required for these units.

3. **ADEM Administrative Code, Rule 335-3-5-.03(1)**, "*Petroleum Production*" applies to the control of sulfur compound emissions from each petroleum production facility that handles gas or refinery gas that contains more than 0.10 grains of hydrogen sulfide ($H_2S$) per standard cubic foot (scf). The Mason 36-14 No. 1 Oil and Gas Production Well will be expected to handle sour gas with more than 0.10 grains of $H_2S$/scf. The gas analysis for the well indicates the $H_2S$ in the well stream is approximately 1,000 ppmv (0.10 mol %) which is considered sour gas. The facility will be required to burn this gas so that the offsite concentration does not exceed 20 ppbv beyond property limits average over a 30 minute period as specified in ADEM Admin. Code R. 335-3-5-.03(2). Vapors from the storage tanks and the produced sour natural gas will be burned in the process flare until the gas can be piped to a processing facility.

4. **ADEM Administrative Code, Rule 335-3-14-.04**, covers the Prevention of Significant Deterioration (PSD). Based on the emissions found in Table 1, this facility would not be expected to exceed the 250 TPY threshold which would trigger a PSD review for this type of facility. Therefore, this project would not be subject to a PSD review.

Additionally, this project is more than 100 km from a Class I area. The emissions from this facility should not have a significant impact on a Class I area. Therefore, no Class I Area analysis will be performed.

5. **ADEM Administrative Code, Rule 335-3-16**, covers Major Source Operating Permits. The Mason 36-14 No. 1 Oil and Gas Production Well would not be subject to the requirements of this regulation. Based on the emissions found in Table 1, the facility would not be expected to exceed the 100 TPY limit for criteria pollutants, the 10 TPY limit for a single HAP, or the 25 TPY limit for a combination of HAPs. At this time, the requirements of Title V would not be applicable to the facility.

**Federal Regulations**

6. **40 CFR 60 Subpart $K_b$**, covers *"Standards of Performance for Volatile Organic Liquid Storage Vessels (including petroleum liquid storage vessels) that are constructed, reconstructed, or modified after July 12, 1984*". 40 CFR 60.110b (d) (4) states that vessels with a design storage capacity of less than, or equal to, 1590 $m^3$ (420,000 gallons) used for petroleum or condensate stored, treated, or processed prior to custody transfer are exempt from this regulation. The facility consists of four 16,800 gallon condensate storage tanks and one 21,000 gallon condensate storage tank that stores condensate prior to custody transfer. The storage capacity of the condensate storage tanks combined would not exceed 420,000 gallons; therefore, the tanks would be exempt from this regulation.

7. **40 CFR 63 Subpart HH**, covers *"National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities"*. 40 CFR 63 Subpart HH which is the MACT for Oil and Gas Production Facilities applies to facilities that are: 1. major <u>or</u> area sources of hazardous air pollutants (HAPs) <u>and</u> either 2. produce, upgrade, or store liquid hydrocarbons prior to custody transfer <u>or</u> 3. produce, upgrade, or store natural gas prior to custody transfer.

   40 CFR 63 Subpart HH could apply to this facility. The requirements of this subpart would depend on whether the well site would be either a major source of HAPs <u>or</u> an area source of HAPs.

   A major source would require 10 TPY of a single HAP or 25 TPY of all HAPs and an area source for Subpart HH would require that the wellsite be a non-major source of HAPs and be equipped with a tri-ethylene glycol dehydration (TEG) unit. The Mason 36-14 No. 1 Oil and Gas Production Well would not be a major source of HAPs; therefore, it would be classified as an area source. Because the well site is not equipped with a TEG dehydration unit this facility would not be subject to the requirements of this subpart.

**Recommendations**

The facility will have to undergo a Greenfield Site Inspection and a 15 day public comment period prior to being issued a permit. Provided there are no comments, I recommend that Venture Oil & Gas, Inc. be issued Air Permit No.: 502-0091-X001 for the Mason 36-14 No. 1 Oil and Gas Production Well. This recommendation is based on the fact that the facility will be burning sour natural gas in the facility flare and it is necessary to ensure that the gas is being properly combusted as required by the regulation. The facility should be able to comply with all state and federal regulations.

Also, provided the Fountain Farm 2-2 No. 1 Oil and Gas Production Well is drilled and testing indicates that this well can produce, it may be necessary to permit the Mason 36-14 No. 1 Oil and Gas Production Well, the Fountain Farm 2-4 No. 1 Oil and Gas Production Well, and the Fountain Farm 2-2 No. 1 Oil and Gas Production Well under one permit.

__________________ November 25, 2009
Harlotte Bolden-Wright Date
Industrial Minerals Section
Energy Branch
Air Division

# ATTACHMENT A:

# CALCULATIONS

## Part A –FLARE CALCULATIONS

The flare calculations are based on continuous flaring. Venture Oil and Gas, Inc. provided the information found in Table A-1 in their permit application. The rated heat capacity would be determined in Equation I by using the gas flowrate and heat content provided in Table A-1.

| **Flowrate** *(scf/hr)* | **Heat Content** *(Btu/scf)* | **$H_2S$** *(mole %)* | **Rated Heat Capacity** *(MMBtu/hr)* |
|---|---|---|---|
| 20,833 | 1,141 | 0.10 | 23.77 |

*Table A-1: Gas Analysis Data*

$$Rated\ Heat\ Capacity\left(\frac{MMBtu}{hr}\right) = Flowrate\left(\frac{scf}{hr}\right) * Heat\ Content\left(\frac{Btu}{scf}\right) * \left(\frac{MMBtu}{10^6\ Btu}\right)$$

[Equation I]

- Calculating $NO_X$ and CO

The AP-42 Emission Factors for flares found in Table 13.5-1 of the Industrial Flares Section are shown in Table A-2. These emission factors would be used to determine the CO and $NO_X$ emissions.

| **Flare AP-42 Emission Factors *(lb/MMBtu)*** | |
|---|---|
| **$NO_X$** | **CO** |
| 0.068 | 0.37 |

*Table A-2: AP-42 Emission Factors for Flares*

Equation II would be used to determine the CO and $NO_X$ emissions produced from the flare. The rated heat capacity and AP-42 emission factors are found in Tables A-1 and A-2, respectively.

$$Emissions\left(\frac{lb}{hr}\right) = Rated\ Heat\ Capacity\left(\frac{MMBtu}{hr}\right) * AP-42\ Emission\ Factor\left(\frac{lb}{MMBtu}\right)$$

[Equation II]

Table A-3 shows the potential $NO_X$ and CO emissions from the flare.

| Potential $NO_X$ and CO Emissions | | | |
|---|---|---|---|
| *(lb/hr)* | | *(Ton/year)* | |
| **$NO_X$** | **CO** | **$NO_X$** | **CO** |
| 1.62E+00 | 8.80E+00 | 7.08E+00 | 3.85E+01 |

*Table A-3: Potential CO and $NO_X$ Emissions*

- Calculating $SO_2$ Emissions

Since the gas analysis shows that the gas stream contains 0.10 mol% of $H_2S$, the emissions would be calculated using Equation III to determine sulfur dioxide ($SO_2$) emissions from the flare.

$$Amount\ of\ SO_2\left(\frac{lb}{hr}\right) = 1.689\left(\frac{lb}{Mscf}\right) * H_2S\,(mole\%) * Flowrate\left(\frac{Mscf}{hr}\right)$$

[Equation III]

$$= 1.689\left(\frac{lb}{Mscf}\right) * 0.10\ mole\%\ H_2S * 2.08E+01\frac{Mscf}{hr} = 3.52E+00\frac{lb}{hr}$$

- Calculating VOC Emissions

In order to estimate the potential VOC emissions, the following assumptions were made:

a. the gas molecular weight = 20 lb/lbmol
b. the VOC mass fraction = 0.40
c. the flare is 98% efficient

The potential VOC emissions would be calculated using Equation IV where the flowrate is given in Table A-1.

$$VOC\ Emissions\left(\frac{lb}{hr}\right) = \left(\frac{Flowrate\left(\frac{scf}{hr}\right) * 20\,\frac{lb}{lb-mol}}{380\,\frac{scf}{lb-mol}}\right) * 0.40 * (1-0.98)$$

[Equation IV]

$$= \left( \frac{20{,}833 \frac{scf}{hr} * 20 \frac{lb}{lb - mol}}{380 \frac{scf}{lb - mol}} \right) * 0.40 * (1 - 0.98) = 8.77 + 00 \frac{lb}{hr}$$

- Total Potential Emissions from the Flare

Table A-4 shows the total potential emissions for the flare assuming constant flaring. The emissions are converted to tons per year by multiplying by a conversion factor of 4.38.

| **Flare Potential Emissions** *(Ton/yr)* | | | |
|---|---|---|---|
| **$SO_2$** | **$NO_X$** | **CO** | **VOC** |
| **1.54E+01** | **7.08E+00** | **3.85E+01** | **3.84E+01** |

*Table A-4: Total Potential Emissions from the Flare*

## Part B –HEATER CALCULATIONS

The emissions from the 0.5 MMBtu/hr line heater and 0.5 MMBtu/hr heater treater are based on the facility burning fuel with a heat content of 1,141 Btu/scf and which contains 0.10 mol % $H_2S$. AP-42 emission factors found in Section 1.4 for Natural Gas Combustion will be used to calculate emissions from these units. The emissions factors are listed in Table B-1.

| AP-42 Emission Factors *(lb/MMscf)* | | | |
|---|---|---|---|
| **PM** | **$NO_X$** | **CO** | **VOC** |
| 7.6 | 100 | 84 | 5.5 |

*Table B-1: AP-42 Emission Factors for NG Combustion Sources*

Equation V will be used to calculate PM, $NO_X$, CO and VOC emissions from the heater treater and the line heater.

$$Emissions\left(\frac{lb}{hr}\right)=\frac{(AP\text{-}42\ Factor\ (lb/MMscf))*(Rated\ Heat\ Capacity\ (MMBTU/hr))}{(Heat\ Content\ (MMBTU/MMscf))}$$

[Equation V]

$SO_2$ emission will be calculated using Equation III from the Flare Calculations section. The flowrate would be determined based on the rated heat capacity of the heaters and the heat content of the fuel gas.

$$1.689\left(\frac{lb}{Mscf}\right)*0.10\ mole\%\ H_2S*4.38E-01\frac{Mscf}{hr}=7.39E\text{-}02\frac{lb}{hr}$$

Table B-2 summarizes the potential emissions from the heaters. The calculated emissions are converted to units of tons per year by multiplying by a conversion factor of 4.38.

| | **Heaters Potential Emission** *(Ton/yr)* | | | | |
|---|---|---|---|---|---|
| **Unit** | **PM** | **$SO_2$** | **$NO_X$** | **CO** | **VOC** |
| **0.5 MMBtu/hr Heater Treater** | 1.46E-02 | 3.24E-01 | 1.92E-01 | 1.61E-01 | 1.06E-02 |
| **0.5 MMBtu/hr Line Heater** | 1.46E-02 | 3.24E-01 | 1.92E-01 | 1.61E-01 | 1.06E-02 |

*Table B-2: Potential Emission from Heaters*

## Part C–FACILITY WIDE EMISSIONS

The potential emissions from the Mason 36-14 No. 1 Oil and Gas Production Well are found in Table C-1.

| | ***Potential Facility-Wide Emissions (Tons/yr)*** | | | | |
|---|---|---|---|---|---|
| | **PM** | **$SO_2$** | **$NO_X$** | **CO** | **VOC** |
| **Line Heater** | 1.46E-02 | 3.24E-01 | 1.92E-01 | 1.61E-01 | 1.06E-02 |
| **Heater Treater** | 1.46E-02 | 3.24E-01 | 1.92E-01 | 1.61E-01 | 1.06E-02 |
| **Process Flare** | | 1.54E+01 | 7.08E+00 | 3.85E+01 | 3.84E+01 |
| **Total PTE** | **2.92E-02** | **1.61E+01** | **7.46E+00** | **3.88E+01** | **3.84E+01** |

*Table C-1: Potential Emission from the Fountain Farm 2-4 No. 1 Well*

# ATTACHMENT B:

# DRAFT PROVISOS

# AIR PERMIT

| | |
|---|---|
| **PERMITTEE:** | VENTURE OIL AND GAS, INC |
| **FACILITY NAME:** | MASON 36-14 NO. 1 OIL & GAS PRODUCTION WELL |
| **LOCATION:** | Section 36, Township 2 North, Range 6 East, Escambia County, AL |

| PERMIT NUMBER | DESCRIPTION OF EQUIPMENT, ARTICLE OR DEVICE |
|---|---|
| 502-0091-X001 | MASON 36-14 NO. 1 OIL & GAS PRODUCTION WELL<br>• One (1) 0.5 MMBTU/hr Line Heater<br>• One (1) 0.5 MMBTU/hr Heater Treater<br>• Closed Vent System & Flare<br>• Storage Tanks with Vapor Recovery Unit<br>o Four (4) 16,800 Gallon Crude Oil Tanks<br>o One (1) 16,800 Gallon Saltwater Tank<br>o One (1) 21,000 Gallon Crude Oil Tank |

*In accordance with and subject to the provisions of the Alabama Air Pollution Control Act of 1971, as amended, Ala. Code §§22-28-1 to 22-28-23 (2006 Rplc. Vol. and 2007 Cum. Supp.) (the "AAPCA") and the Alabama Environmental Management Act, as amended, Ala. Code §§22-22A-1 to 22-22A-15 (2006 Rplc. Vol. and 2007 Cum. Supp.), and rules and regulations adopted there under, and subject further to the conditions set forth in this permit, the Permittee is hereby authorized to construct, install and use the equipment, device or other article described above.*

**ISSUANCE DATE:** draft 12/2/2009

Alabama Department of Environmental Management

VENTURE OIL AND GAS, INC
MASON 36-14 NO. 1 OIL & GAS PRODUCTION WELL
ESCAMBIA COUNTY, ALABAMA
(PERMIT NO. 502-0091-X001)
PROVISOS

1. This permit is issued on the basis of Rules and Regulations existing on the date of issuance. In the event additional Rules and Regulations are adopted, it shall be the permit holder's responsibility to comply with such rules.

2. This permit is not transferable. Upon sale or legal transfer, the new owner or operator must apply for a permit within 30 days.

3. A new permit application must be made for new sources, replacements, alterations or design changes which may result in the issuance of, or an increase in the issuance of, air contaminants, or the use of which may eliminate or reduce or control the issuance of air contaminants.

4. Each point of emission will be provided with sampling ports, ladders, platforms, and other safety equipment to facilitate testing performed in accordance with procedures established by Part 60 of Title 40 of the Code of Federal Regulations, as the same may be amended or revised.

5. In case of shutdown of air pollution control equipment for scheduled maintenance for a period greater than **8 hour,** the intent to shut down shall be reported to the Air Division at least 24 hours prior to the planned shutdown, **unless accompanied by the immediate shutdown of the emission source.**

6. In the event there is a breakdown of equipment in such a manner as to cause increased emission of air contaminants for a period greater than **2 hour**, the person responsible for such equipment shall notify the Air Division within an additional 24 hours and provide a statement giving all pertinent facts, including the duration of the breakdown. The Air Division shall be notified when the breakdown has been corrected.

7. This process, including all air pollution control devices and capture systems for which this permit is issued, shall be maintained and operated at all times in a manner so as to minimize the emissions of air contaminants. Procedures for ensuring that the above equipment is properly operated and maintained so as to minimize the emission of air contaminants shall be established.

8. This permit expires and the application is cancelled if construction has not begun within 24 months of the date of issuance of the permit.

9. On completion of construction of the device for which this permit is issued, notification of the fact is to be given to the Chief of the Air Division. Authorization to operate the unit must be received from the Chief of the Air Division. Failure to notify the Chief of the Air Division of completion of construction and/or operation without authorization could result in revocation of this permit.

10. Submittal of other reports regarding monitoring records, fuel analyses, operating rates, and equipment malfunctions may be required as authorized in the Department's air pollution control rules and regulations. The Department may require stack emission testing at any time.

11. Additions and revisions to the conditions of this Permit will be made, if necessary, to ensure that the Department's air pollution control rules and regulations are not violated.

12. Nothing in this permit or conditions thereto shall negate any authority granted to the Air Division pursuant to the Alabama Environmental Management Act or regulations issued thereunder.

13. The Air Division must be notified in writing at least 10 working days in advance of all emission tests to be conducted and submitted as proof of compliance with the Department's air pollution control rules and regulations.

    To avoid problems concerning testing methods and procedures, the following shall be included with the notification letter:

    (a) The date the test crew is expected to arrive, the date and time anticipated of the start of the first run, how many and which sources are to be tested, and the names of the persons and/or testing company that will conduct the tests.

    (b) A complete description of each sampling train to be used, including type of media used in determining gas stream components, type of probe lining, type of filter media, and probe cleaning method and solvent to be used (if test procedure requires probe cleaning).

    (c) A description of the process(es) to be tested, including the feed rate, any operating parameter used to control or influence the operations, and the rated capacity.

    (d) A sketch or sketches showing sampling point locations and their relative positions to the nearest upstream and downstream gas flow disturbances.

    A pretest meeting may be held at the request of the source owner or the Department. The necessity for such a meeting and the required attendees will be determined on a case-by-case basis.

    All test reports must be submitted to the Air Division within 30 days of the actual completion of the test, unless an extension of time is specifically approved by the Air Division.

14. This permit is issued with the condition that, should obnoxious odors arising from the plant operations be verified by Air Division inspectors, measures to abate the odorous emissions shall be taken upon a determination by the Alabama Department of Environmental Management that these measures are technically and economically feasible.

15. Precautions shall be taken to prevent fugitive dust emanating from plant roads, grounds, stockpiles, screens, dryers, hoppers, ductwork, etc.

16. Plant or haul roads and grounds will be maintained in the following manner so that dust will not become airborne. A minimum of one, or a combination, of the following methods shall be utilized to minimize airborne dust from plant or haul roads and grounds:

    (a) by the application of water any time the surface of the road is sufficiently dry to allow the creation of dust emissions by the act of wind or vehicular traffic;

    (b) by reducing the speed of vehicular traffic to a point below that at which dust emissions are created;

    (c) by paving;

    (d) by the application of binders to the road surface at any time the road surface is found to allow the creation of dust emissions;

    Should one, or a combination, of the above methods fail to adequately reduce airborne dust from plant or haul roads and grounds, alternative methods shall be employed, either exclusively or in combination with one or all of the above control techniques, so that dust will not become airborne. Alternative methods shall be approved by the Department prior to utilization.

17. This process shall be operated at all times in a manner so as to minimize the emission of air contaminants. Procedures for ensuring that the process is properly operated and maintained so as to minimize the emission of air contaminants shall be established.

18. The permittee shall not use as a defense in an enforcement action that maintaining compliance with conditions of this permit would have required halting or reducing the permitted activity.

19. The issuance of this permit does not convey any property rights of any sort, or any exclusive privilege.

20. The Mason 36-14 No. 1 Oil and Gas Production well handles gas or refinery gas that contains more than 0.10 grains of hydrogen sulfide ($H_2S$) per standard cubic foot of gas.

21. All process gas streams containing 0.10 of a grain of hydrogen sulfide per Scf shall be burned to the extent that the ground level concentrations of hydrogen sulfide shall be less than twenty (20) parts per billion beyond plant property limits, averaged over a thirty (30) minute period.

22. Compliance with proviso 21 of this permit shall be demonstrated by complying with the requirements specified in proviso 22(a) through (c) of this permit.

(a) Except as provided for in proviso 22(a)(2), each process gas stream that has to vented to the atmosphere shall be captured and sent through a closed vent system to the flare to be combusted.

(1) Compliance shall be demonstrated by conducting a process flow design evaluation of each site in conjunction with visible inspection of each.

(2) Except when vessels and equipment are being de-pressured and/or emptied and the reduced pressure will not allow flow of the gas to the flare, the venting to the atmosphere of any process gas stream shall not occur for a duration in excess of 15 continuous minutes.

(b) Maintaining the maximum $H_2S$ feedrate to the flare at less than 500 lb/hr.

(c) Testing each process gas stream that may be sent to the flare as specified in proviso 22 (c)(1) through (4) of this permit.

(1) Determine the $H_2S$ content for each process gas that can be sent to the flare as follows:

(i) Capture one representative sample of the stream at a frequency of no less than once each month.

(ii) Analyze the sample collected utilizing the Tutwiler procedures in 40 CFR §60.648, chromatographic analysis procedures found in ASTM E-260, the stain tube procedures found in GPA 2377-86 or those provided by the stain tube manufacturer, or other methods and procedures approved by the Department.

[SG Stream ($H_2S$ Mole %)]

(2) Determine the Btu content for each process gas that can be sent to the flare as follows:

(ii) Capture one representative sample of the stream at a frequency of no less than once each month.

(iii) Analyze the sample for its Btu content by utilizing the ASTM Analysis Method D1826-77 or other equivalent method.

[SG Stream (BTU/Scf)]

(3) Provided multiple process streams can be sent to the flare and it is possible to capture a common stream whose contents would be representative of all the streams, that common stream may be used instead of the individual process streams.

(4) The frequency of testing may be modified upon receipt of Departmental approval.

23. Monitoring to demonstrate compliance with proviso 21 of this permit shall be met by maintaining the presence of a spark or flame at the flare tip at all times a process gas stream may be sent to the flare.

24. To demonstrate compliance with proviso 23 of this permit, a daily visual inspection of the flare shall be conducted as specified in proviso 24 (a) through (c), except when the facility is not being manned by plant personnel or when process gas can not be sent to the flare.

    (a) Visual inspections shall be made from a location that provides the best view of the flare tip and/or flare pilot lights or flare igniter.

    (b) A record of the time, date, and results of each visual inspection of the flare shall be maintained.

    (c) Provided that a spark or flame is not present at the flare tip when process gas can be sent to the flare, a record of the time, date, duration, and corrective actions taken for each incident shall be maintained.

25. When possible and practicable, a continuous metering system shall be utilized that is capable of continuously monitoring and recording the flow rate of each sour gas stream that is to be vented to the flare prior to entry into the flare.

    (a) The continuous measurement may be made with a single meter through which all of the sour gas steams flow, or with multiple meters through which an individual sour gas stream or multiple sour gas streams flow.

        (1) Calibration, maintenance and operation of metering system shall be performed in accordance to manufacturer's specification.

    (b) Volumetric flow of sour gas streams that are not continuously measured shall be accounted for by utilizing special estimating methods (i.e. engineer estimates, material balance, computer simulation, special testing, etc).

26. The flare shall meet the requirements specified in proviso 26(a) and (b) of this permit.

    (a) Except for one 6-minute period during any 60-minute period, the flare shall not discharge into the atmosphere particulate that results in an opacity greater than 20%, as determined by a 6-minute average.

    (b) At no time shall the flare discharge into the atmosphere particulate that results in an opacity greater than 40%, as determined by a 6-minute average.

27. Compliance with proviso 26 of this permit shall be demonstrated by performing a daily visible emission observation on the flare as specified in provisos 27 (a) through (d) of this permit, except when the facility is not being manned by plant personnel or when process gas can not be sent to the flare.

(a) 40 CFR Part 60 Appendix A Method 9 or 40 CFR Part 60 Appendix A Method 22 or other methods and procedures approved by the Department shall be utilized to perform the daily visible emission observations.

(1) Visible emission observations utilizing Method 9 shall be conducted by an observer certified in Method 9 methods and procedures.

(2) Visible emission observations utilizing Method 22 shall be conducted by an observer that is familiar with Method 22 methods and procedures.

(3) Visible emissions that are observed utilizing Method 22 shall be deemed to have a reading in excess of 20% opacity and visible emission shall not be observed for more than one 6-minute period within a 60-minute observation period.

(4) Visible emission observations shall be conducted during daylight hours.

(b) The duration of each observation shall be no less than fifteen consecutive minutes.

(c) Provided visible emission are observed in excess of the opacity standards, immediate corrective measures shall be undertaken to eliminate the visible emissions.

(d) A record of the time, date, duration, and immediate corrective actions taken to eliminate visible emissions shall be maintained.

28. The following records shall be maintained on a monthly basis and kept in a form suitable for inspection:

(a) Volume of gas burned in flare=

[Stream Volume Burned (MScf/Month)]

(b) Stream (MMBtu/Month)=

[Stream Volume Burned (MScf/Month) ] X [ Sour Gas (SG) Stream (Btu/Scf) ] X [ 1 MMScf/1000 MScf ]

(c) Stream $H_2S$ (Lbs/Month) =

[Stream Volume Burned (MScf/Month) ] X { 1000 Scf/MScf ] X [1 Mole/380 Scf) ]X [ {SG Stream ($H_2S$ Mole%)}/{100} ] X[ 34 Lbs. $H_2S$/Mole $H_2S$ ]

(d) Flare $H_2S$ (Lbs/Month) =

∑ of Stream $H_2S$ (Lbs/Month)

(e) Number of hours that the flare was operated during the month=

[Flare (Hours/Month)]

(f) Flare $H_2S$ feed (Lbs/Hour) =

$$\frac{\text{Flare } H_2S \text{ (Lbs/Month)}}{\text{Flare (Hours/Month)}}$$

(g) Records of each daily visual inspections of the flare tip for the presence of a spark or flare.

(h) Record of each daily visible emission observations conducted on the flare.

(i) Record of the date, starting time and duration of each deviation from the requirements specified in this permit along with the cause and corrective actions taken.

29. The frequency of recordkeeping may be modified upon receipt of Department approval.

30. All records shall be maintained in a permanent form suitable for inspection and shall be retained for at least two (2) years following the date of each occurrence, including the occurrence and duration of any startup, shutdown, or malfunction in the operation of the process equipment and any malfunction of the air pollution control equipment.

31. Periodic monitoring reports meeting the following requirements shall be submitted to the Department:

(a) Report contents shall be:

(1) A summary of the monthly records kept per proviso 28 of this permit

OR

(2) As otherwise approved by the Department

(b) Reporting frequency shall be:

(1) Semi-annually,

OR

(2) As otherwise approved by the Department.

(c) Reports shall be submitted on a calendar basis.

(d) Each report shall be submitted within thirty (30) days of the end of the reporting period.

32. All deviations from requirements within this permit shall be reported to the Department within 48 hours of the deviation or by the next work day while providing a statement with regards to the date, time, duration, cause and corrective actions taken to bring the sources back into compliance. A review and evaluation of this report shall be utilized in Departmental determination of whether or not a violation of a permit requirement or requirements occurred.

December 2, 2009
Draft Date